2017 MECHANICAL INTEGRITY AND RESERVOIR TESTING
CLASS I HAZARDOUS DEEPWELL
Well #1-12; UIC Permit: MI-163-1W-C0007

Environmental Geo-Technologies, LLC
Romulus, Michigan

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1.0 INTRODUCTION

All Class I Waste Disposal Wells must demonstrate mechanical integrity as required by the United States Environmental Protection Agency (USEPA) under the Underground Injection Control (UIC) Program and MDEQ Mineral Well Act. The mechanical integrity tests (MITs) conducted July 17 through July 19, 2017 at the Environmental Geo-Technologies, LLC (EGT) Romulus, Michigan facility (Well No. 1-12) demonstrated that "there is no significant leak in the casing, tubing or packer", that no evidence of flow exists behind pipe at the base of the casing strings, and that injection zone pressures have not changed sufficiently from previous testing to warrant further investigation.

This report summarizes the successful MIT activities performed at the Environmental Geo-Technologies, LLC (EGT) Romulus, Michigan facility. The work was performed as a condition of the EGT UIC permit issued by the USEPA and MDEQ. All annual MIT requirements for Well No. 1-12 were satisfied as a result of the work performed. Under contract, Petrotek Engineering Corporation developed the MIT procedures, provided field supervision, provided pressure transient test and logging analysis and prepared the final report documenting the MIT fieldwork on the Class I hazardous injection well located at the Romulus facility.

The test procedures were submitted to the USEPA Region 5 office and the MDEQ field inspector prior to field activities. In addition, field inspectors were notified by phone of the scheduled MIT fieldwork to allow regulatory agency witnessing of the tests. Mr. Jack Lanigan of the MDEQ was present to witness this testing. Approvals were received from regulatory agency staff prior to commencement of activities. The procedures included information about temperature logging. However, since a temperature run was run in 2016, EGT notified EPA that no temperature log would be run for 2017. Temperature logging for Well No. 1-12 at the EGT facility is required on a 3-year schedule. The next temperature log for Well No. 1-12 will be run in 2019.

The MIT activities consisted of an annulus pressure test, injection falloff test and a radioactive tracer survey (RTS) on Well No. 1-12. The well satisfactorily demonstrated mechanical integrity pursuant to the EGT Underground Injection Control (UIC) permit, applicable guidelines and regulations. Well No. 1-12 wellbore and reservoir properties were confirmed as similar to those determined from analysis of the previous testing conducted in the well.

2.0 MECHANICAL INTEGRITY TESTING

The year 2017 MIT activities on EGT waste injection Well No. 1-12 were supervised by Rich Schildhouse of Petrotek. The MIT activities occurred July 17 through July 19, 2017. The procedures followed in the tests were approved in advance by EPA and MDEQ representatives and all tests were witnessed by Mr. Jack Lanigan of MDEQ. Appendix 1 presents approvals and test procedures. Figure 1 presents a wellbore diagram illustrating the configuration of the well during testing activities. Note that no changes to the subsurface wellbore configuration were made to the well at the time of testing during 2017 or since MIT activities were last completed in 2016.

Part I: Internal Mechanical Integrity

As previously indicated, the MIT activities conducted in 2017 consisted of an injection falloff test, which is discussed in Section 3 of this report, static annulus pressure test and a RTS (RAT) log.

On July 17, 2017 the annulus of Well No. 1-12 was pressured up to 967.7 psi. A calibrated digital pressure gauge (Fluke 3,000 psi, SN-2643157) supplied by Petrotek was installed on the annulus at the wellhead. After the well was isolated from the surface equipment, Petrotek and the MDEQ inspector monitored static annulus pressure or the well annulus for a period of one hour at 10-minute intervals. During the 60-minute test period, the pressure decreased by 0.6 psi, which is a 0.06% change. Since a change of 3% or (29.0 psi) of the test pressure is allowable, this test is within acceptable specifications. A copy of the field measurements of the annular pressure test results recorded on the MDEQ annulus pressure test summary are included as Appendix 2. Appendix 3 presents a copy of the gauge certification. Subsequent to the completion of the test, the annulus tank valve was opened and pressure in the annulus system was lowered by 254 psi and a rise in annulus fluid level of approximately 3 gallons was observed. Well No. 1-12 pressures were observed as follows during testing.

TABLE 1

STATIC ANNULUS PRESSURE TEST MEASUREMENTS
WELL NO. 1-12 (JULY 17, 2017)
EGT, ROMULUS, MICHIGAN

Time, Minutes	0	10	20	30	40	50	60
Pressure, psi	967.7	967.7	967.6	967.4	967.3	967.2	967.1

Part II: External Mechanical Integrity

Radioactive Tracer Survey - The primary purpose of an RTS Survey is to verify the adequacy of the bottomhole cement surrounding the base of a long string casing. An RTS log was conducted on EGT Well #1-12 in accordance with the approved MIT testing procedures submitted to MDEQ and EPA prior to commencement of field activities and are consistent with USEPA Region 5 guidance documents pertaining to mechanical integrity testing.

General Procedure – RTS

A. Disconnect surface equipment and rig-up pressure control equipment.

B. Run in well with RTS tool and two gamma-ray detectors located below the injector port.

C. Correlate log to existing logs (noting Kelly Bushing). Correlate RTS log to packer and/or natural gamma ray responses. Locate bottom of well if practical or run to at least 100 feet below casing shoe to a depth of not less than approximately 4,200 feet KB if attainable based on wellbore conditions and pull base log a minimum of depth of 3,093 feet KB, or shallower. Run a minimum of one five-minute statistical log in two different lithologies (3,955 and 3,802 feet KB).

D. Start or continue or injection using water at approximately 15 - 50 gpm. Release the first slug in the tubing at a depth above the packer and observe the movement as it passes the lower detector. Record the movement of the slug by repeatedly moving the tool down hole and making a series of overlapping passes as the slug dissipates into the openhole formation.

E. Continue to monitor the slug until there is no indication that it is moving up behind the long string casing.

F. Pull tools into the tubing and release a slug at approximately 3,750 feet KB while injecting. RIH and position the bottom gamma-ray detector at a depth of approximately 4,080 feet KB. Leave the tool stationary and record the log in time drive for 30 minutes while continuing to inject. Run a final base log. At the conclusion of the test, rig down wireline and support equipment.

A copy of the field recorded radioactive tracer survey log in paper form are included as Attachment 1 of this document. Attachment 4 provides digital copies.

Well #1-12 - RTS

On July17, 2017, a radioactive tracer (RTS) was performed on Well #1-12. Depths were correlated to past logs and well configuration, and a gamma-ray base log was run from approximately 4,518 feet to 3,071 feet and five-minute statistical logs were run with the top detector at 3,797 feet and at 3,950 feet. The bottom detector was 5 feet below the top detector at each station. Using the site equipment, fluid was then injected at approximately 30 gallons per minute. A slug was released at approximately 3,750 feet and the tool was lowered placing the bottom detector at 4,080 feet where a 30-minute time drive was conducted. The slug passed the tool at approximately 280 seconds and no upward movement of the tracer was observed after the slug passed the tool as it was injected down the tubing.

After the time drive log was complete the tool was then moved to a depth of 3,100 feet and a slug was released to begin the chase series. A total of 13 passes were run and the slug was observed to enter the injection interval below the casing shoe at 4,080 feet. The tracer materials all moved into the injection interval and there was no indication of any significant movement above the casing shoe or above the top of the injection interval or injection zone. A final base log was then run with a majority of the residual tracer detected from approximately 4,270 to 4,350 feet and the log was approved by the MDEQ field inspector. A paper copy of the log is provided as Attachment 1 and a PDF copy of the log is provided as Attachment 4.

3.0 RESERVOIR TESTING

3.1 Data Collection

Injection-falloff pressure transient data were collected from EGT, Well No. 1-12 at the Romulus, Michigan site July 19-20, 2017. The year 2017 annual reservoir testing was supervised by Rich Schildhouse of Petrotek. Parameters supplied for the Mt. Simon injection interval and the test synopsis are summarized in Attachment 3. Raw data collected by J.O. Well Service are provided as Attachment 4. A J. O. Well Service quartz gauge was utilized to acquire bottomhole pressure data. Downhole gauge calibration information is presented as Appendix 4 of this document.

Test Injection began at 10:40 on July 19, 2017. Within approximately twenty minutes, a stable injection rate of approximately 25.8 gallons per minute (gpm) was achieved. At approximately 11:10, the tool assembly was set at the test depth of 3,937 feet BGL (3,950' RKB) while injection continued. The offset Well No. 2-12 had been shut-in since June 14, 2017 and was not operated during the Well No. 1-12 injection or falloff data collection period. Bottomhole injection pressure and temperature were recorded for approximately 10.5 hours prior to start of the falloff test. A bottomhole injection pressure of 2,143 psig at 3,950 feet RKB (3,937' BGL) at a flow rate of approximately 25.8 gpm was recorded during the final one-hour injection period prior to falloff testing.

Well No. 1-12 was shut-in at approximately 21:34 on July 19, 2017 by stopping the injection pump while concurrently closing the wellhead valve and pump-house valves and shut-in was completed within several minutes. Over the final several minutes of flow, rate dropped from 25.8 gpm to 20.2 gpm. Final flow rate was 20.2 gpm (692.6 bpd) and final bottomhole pressure at shut-in was 2,079.9 psig.

After shut-in of Well No. 1-12, pressure falloff in the injection interval was recorded for approximately 10.4 hours after Well No. 1-12 injection was stopped. Pressure had declined to a minimum of approximately 1,794.4 psig by the end of the test. Injection and falloff pressures appear to be of similar magnitude to values measured in previous tests. At the end of the test, static gradient stops made as the tool was pulled from the the well indicated a fluid gradient of approximately 0.424 psi/ft.

3.2 Data Analysis

As summarized in Attachment 3, there are a number of items critical to test analysis. These include data regarding the well and formation, along with data regarding the fluids involved in the testing process. Consistent with past analyses, evaluation of these data was conducted using a value of 133 feet estimated as a probable effective thickness. Other reservoir and fluid parameters were utilized, as reported in the testing conducted during 2015 through 2016, with the exception of rate and time, which are test dependent. For testing during 2017, rates were determined based on site monitoring equipment. A value of 0.798 centipoise was assigned as a representative viscosity of the fluids through which the pressure transients analyzed in this test traveled based on previous analyses.

The following figures have been prepared to examine and analyze the pressure transient data collected from EGT Well No. 1-12 during 2017 reservoir testing. These include: Figures 2 - Cartesian Plot of Pressure, Temperature and Rate vs. Time; Figure 3 - Cartesian Plot of Pressure Falloff; Figure 4 - Radial Flow Derivative/Log-log Plot (Dp vs. Dt); Figure 5 - Radial Flow Semilog/Horner Plot of Pressure Falloff; Figure 6 - Composite Model Test Rate History and Pressure Match; Figure 7 - Composite Model Derivative Match; and Figure 8 - Composite Model Semilog/Horner Match. Attachment 4 includes a digital copy of the falloff pressure data.

Figure 2 is chronological plot of pressure and rate data collected with the bottomhole pressure gauge, and flow data collected with the plant monitoring equipment for the entire duration of the test on Well No. 1-12. Figure 3 is an expanded Cartesian plot of the downhole data during the falloff test. It is evident from examination of the log-log plot (Figure 4) that very early time data are dominated by wellbore storage. Soon after, the slope of both the pressure and pressure derivative decrease during a period that is dominated by changing wellbore storage. No square root pseudo-slopes are apparent in the test. Examination of Figure 4 shows that after a time of approximately 1 hour, the middle time data collected appear to be starting to transition into radial flow in the injection zone.

A transition from the middle-time radial flow to late-time flow is clearly evident after a time of approximately 3 to 4 hours where classical radial flow does not appear to be present. This is likely associated with historical offset injection in the nearby site well (No. 2-12) prior to the test and likely obscures the falloff behavior that otherwise would be dominated by the external portion of the composite reservoir system. Assuming a single well in an infinite reservoir, a permeability-thickness of approximately 14,160 md-ft and a P* value of 1,807 psia (3,937' BGL) are derived. At the end of the falloff, pressure had decayed to a value of approximately 1,809 psia. For an effective reservoir thickness of 133 feet, a permeability of 106.5 md is derived. A skin factor of 43.9 is derived in this analysis.

The Semi-log Horner Plot presented as Figure 5 shows the period of possible radial flow consistent with the diagnostic plots. As noted on page 18 of the SPE Well Testing Textbook by Lee (1982), pseudo-producing time tp, was assigned for the Horner analysis by dividing the cumulative injection into the well during the test by the final test flow rate before shut-in. Based on a test period injection into Well No. 1-12 of approximately 410 barrels since the most recent shut-in before the test and a final rate of 20.2 gpm, tp is equal to 14.19 hours. Figures 6, 7and 8 present analysis of the data generated with a composite radial flow model with a no-flow boundary condition to account for historical offset injection. A permeability-thickness of approximately 13,442 md-ft and a P* value of 1,805 psia (3,937' BGL) are derived. At the end of the falloff, pressure had decayed to a value of approximately 1,809 psia. It is noted that some pressure support from ongoing offset injection served to increase these values as compared to values that would have been measured if all wells on site were shut-in during testing. For an effective reservoir thickness of 133 feet, an average permeability of 101 md is derived from the simulation. A skin factor of 39.8 is derived in this analysis. This analysis is not atypical as compared with permeability that may exist at some distance from the wellbore and the large skin value is consistent with some historical injectivity declines.

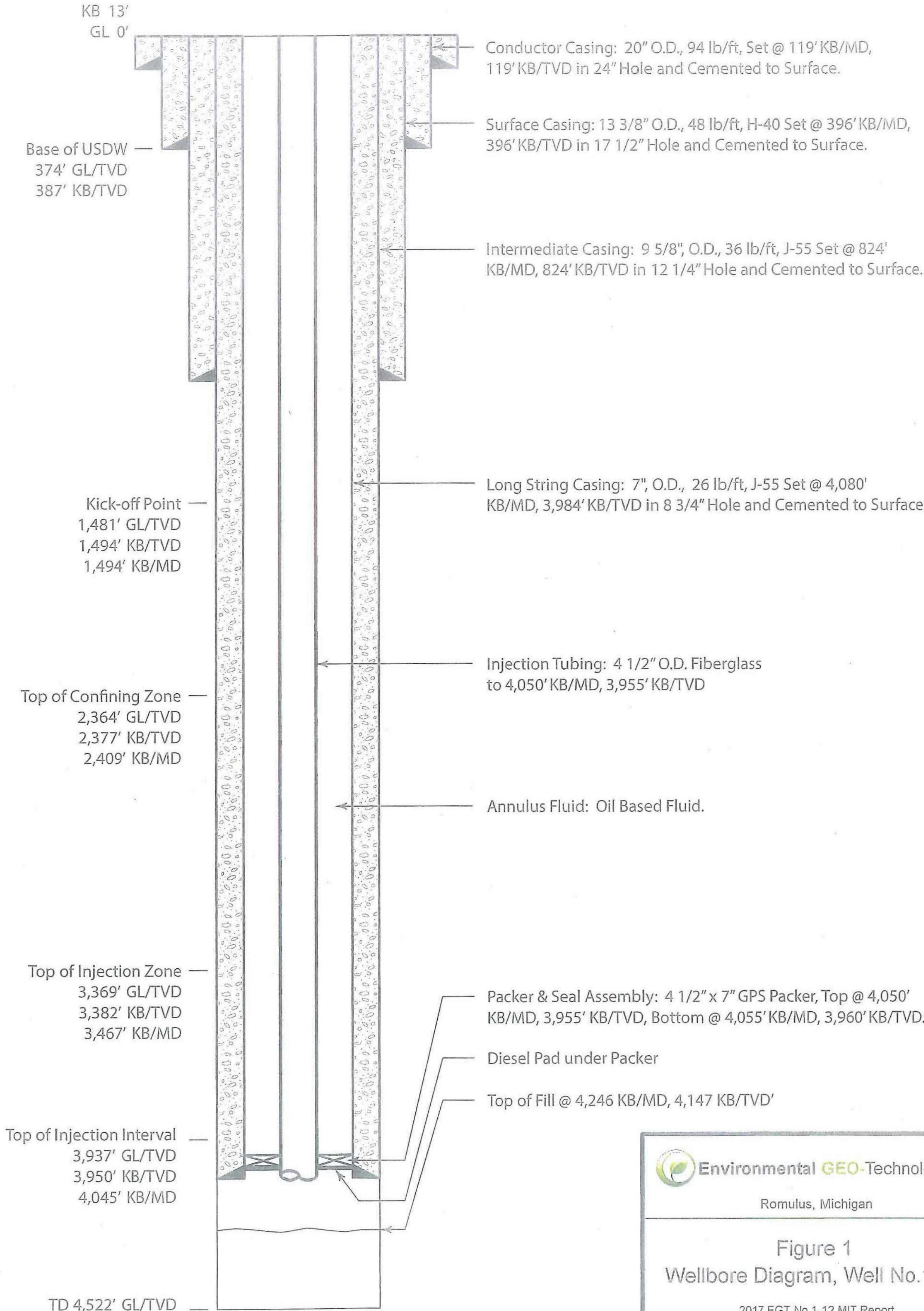
Table 2 presents a comparison of the 2015 through year 2017 falloff analysis results. Results are reasonably consistent with values observed locally for the Mt. Simon Formation. In summary, standard industry data collection and analysis procedures were followed with respect to this testing. Appropriate graphs of the data are provided as Figures 5 through 8, which clearly show the relationship of pressure, temperature and time with a simulation analysis. Analysis of the Well No. 1-12 falloff data utilizing the classical infinite acting case and a simple single boundary simulation to estimate the impact of the offset Well No. 2-12 yield values consistent with those expected in this well.

TABLE 2
HISTORICAL RESERVOIR PRESSURE MEASUREMENTS
EGT, ROMULUS, MICHIGAN - WELL NO. 1-12

Well ID	Date	Gauge Depth (feet KB)	kh (md-ft)	k (md)	Skin	P* (psig)	Final Shut-in Pressure (psig) @ Gauge Depth
1-12	2015	3,950	20,216	152	84	1,773	1,774.9
1-12	2016	3,950	22,225	165	41	1,755	1,761.3
1-12	2017	3,950	14,160	106	44	1,792	1,794.0

Site well performance continues to be influenced by skin damage (or effective permeability-thickness communicating to the wellbore). Some uncertainty is present in the analysis due to interference from the offset well, but general test conclusions are not altered by this factor. If skin increases or near wellbore permeability decreases, well injectivity will tend to decrease. At this time, a majority of the pressure buildup during injection is due to skin damage or near wellbore permeability restrictions. This accounts for a majority of the pressure rise currently observed during injection operations. If it were economically or technically practical to eliminate the skin, the formation could have the capability to accept fluid at higher injection rates with a lower wellhead pressure.

The objective of the annual reservoir testing was to identify significant injectivity changes or new wellbore problems and to confirm that formation properties and pressures have not changed significantly from those expected. These goals were successfully achieved and no significant concerns relevant to continued operation, safety or containment were identified. The current EGT data acquisition and wellhead injection pressure monitoring practices will provide indications of injectivity changes and are sufficient to ensure continued operation at permitted injection pressures. This testing and analysis confirms that the EGT, Well No. 1-12 at Romulus and the disposal reservoir remains suitable for continued disposal use.



Note:
True bottom of Well is 211' South & 754' West of surface location.
Ground Level Elevation 626.6'
From: WSP / Parsons Brinckerhoff, 09/2016 Figure 6

Environmental GEO-Technologies

Romulus, Michigan

Figure 1
Wellbore Diagram, Well No.1-12

2017 EGT No.1-12 MIT Report

Scale: NTS	Date: August 2017	
2017_EGT_No1-12_Wellbore.ai	By: JLM	Checked: WJ

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Environmental Geo-Technologies, LLC; Romulus, Michigan
July 2017 Annual Reservoir Test, Well No. 1-12
Figure 2 - Cartesian Plot of Pressure, Temperature and Rate vs. Time

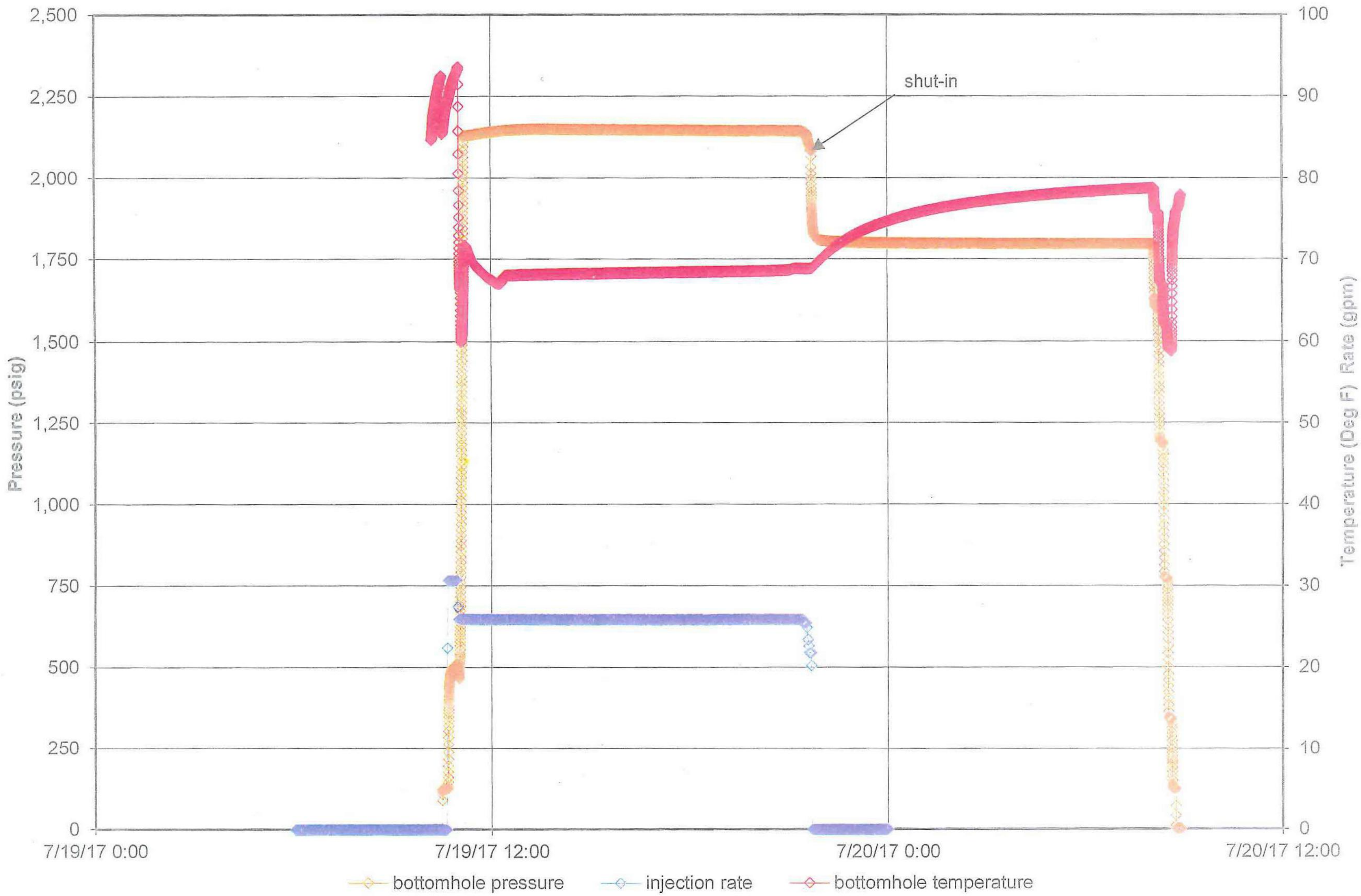
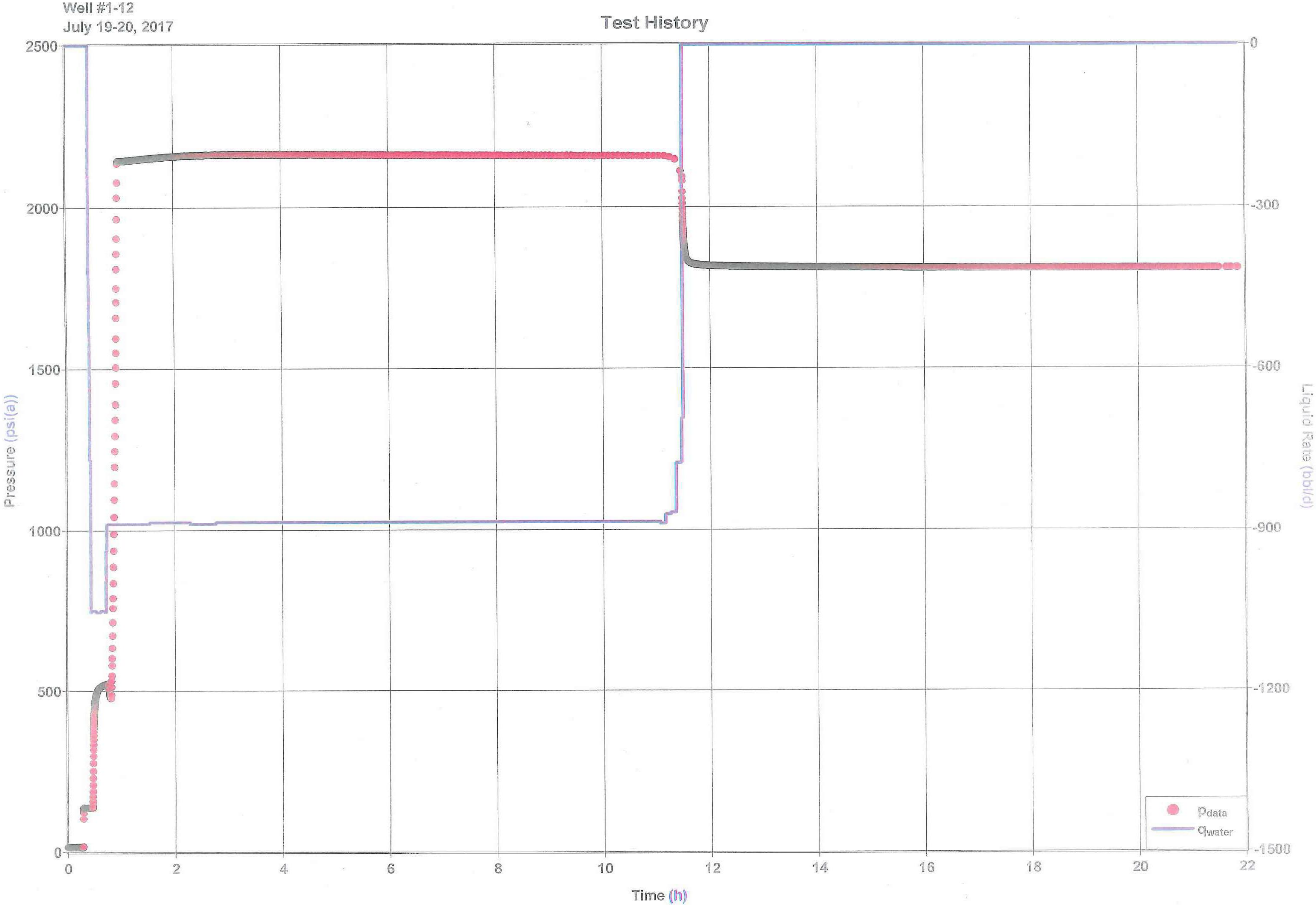


Figure 3 - Cartesian Plot of Pressure Falloff

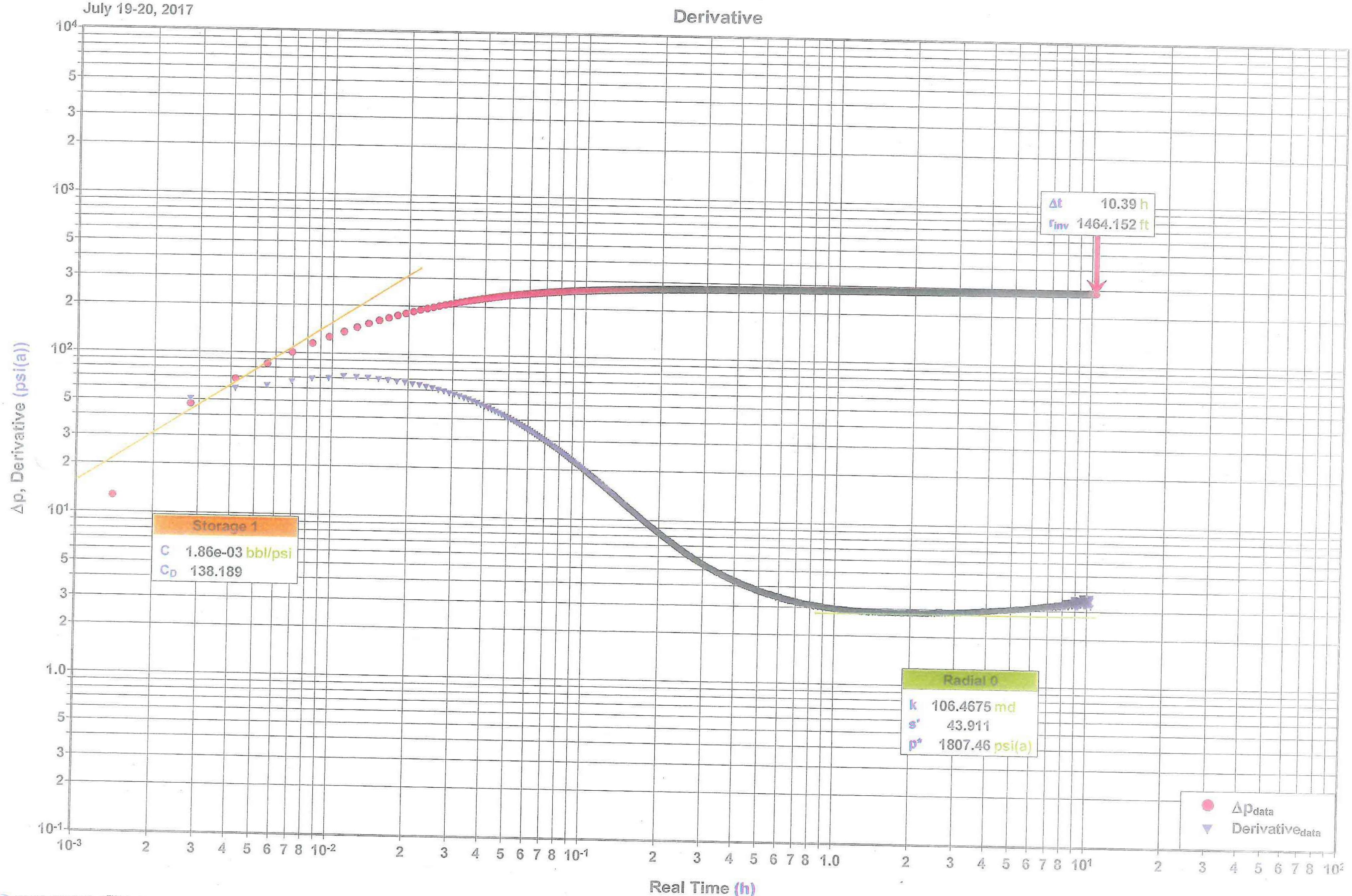
Environmental Geo-Technologies, LLC
Well #1-12
July 19-20, 2017



WellTest32 2016 v2™ Ver 7.13.0.167
C:\Petrotek\EGT 2017\EGT Well #1 WTA.fkt 17-Aug-17

Figure 4 - Radial Flow Derivative/Log-log Plot (Dp vs. Dt)

Environmental Geo-Technologies, LLC
Well #1-12
July 19-20, 2017



WellTest32 2016 v2™ Ver 7.13.0.167
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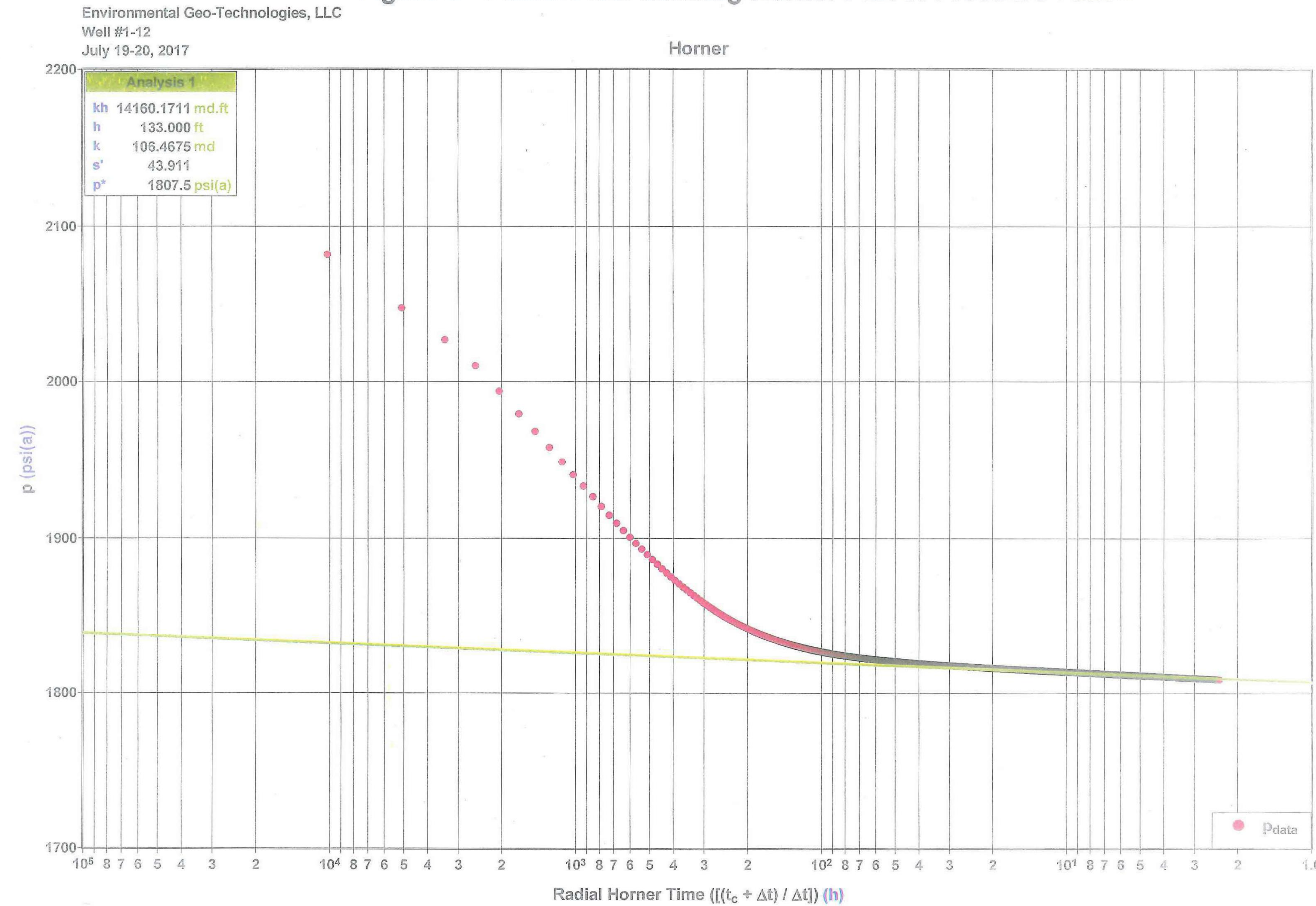
Figure 5 - Radial Flow Semilog Horner Plot of Pressure Falloff



WellTest32 2016 v2™ Ver 7.13.0.167
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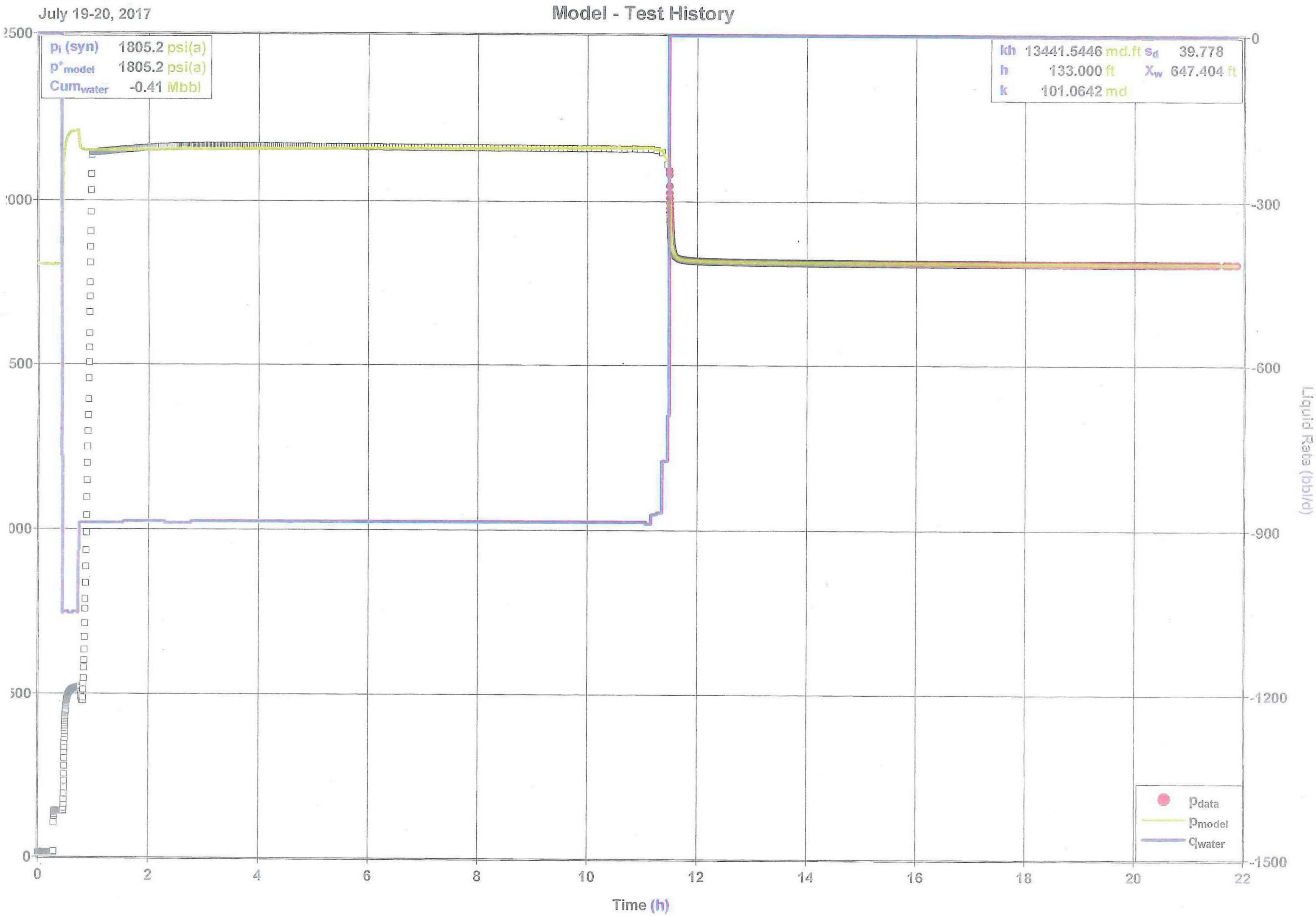
Figure 6 - Composite Model Test Rate History and Pressure Match

Environmental Geo-Technologies, LLC
Well #1-12
July 19-20, 2017



est32 2016 v2™ Ver 7.13.0.167
rotek\EGT 2017\EGT Well #1 WTA.fkt 20-Aug-17

Figure 7 - Composite Model - Derivative Match

Environmental Geo-Technologies, LLC
Well #1-12
July 19-20, 2017

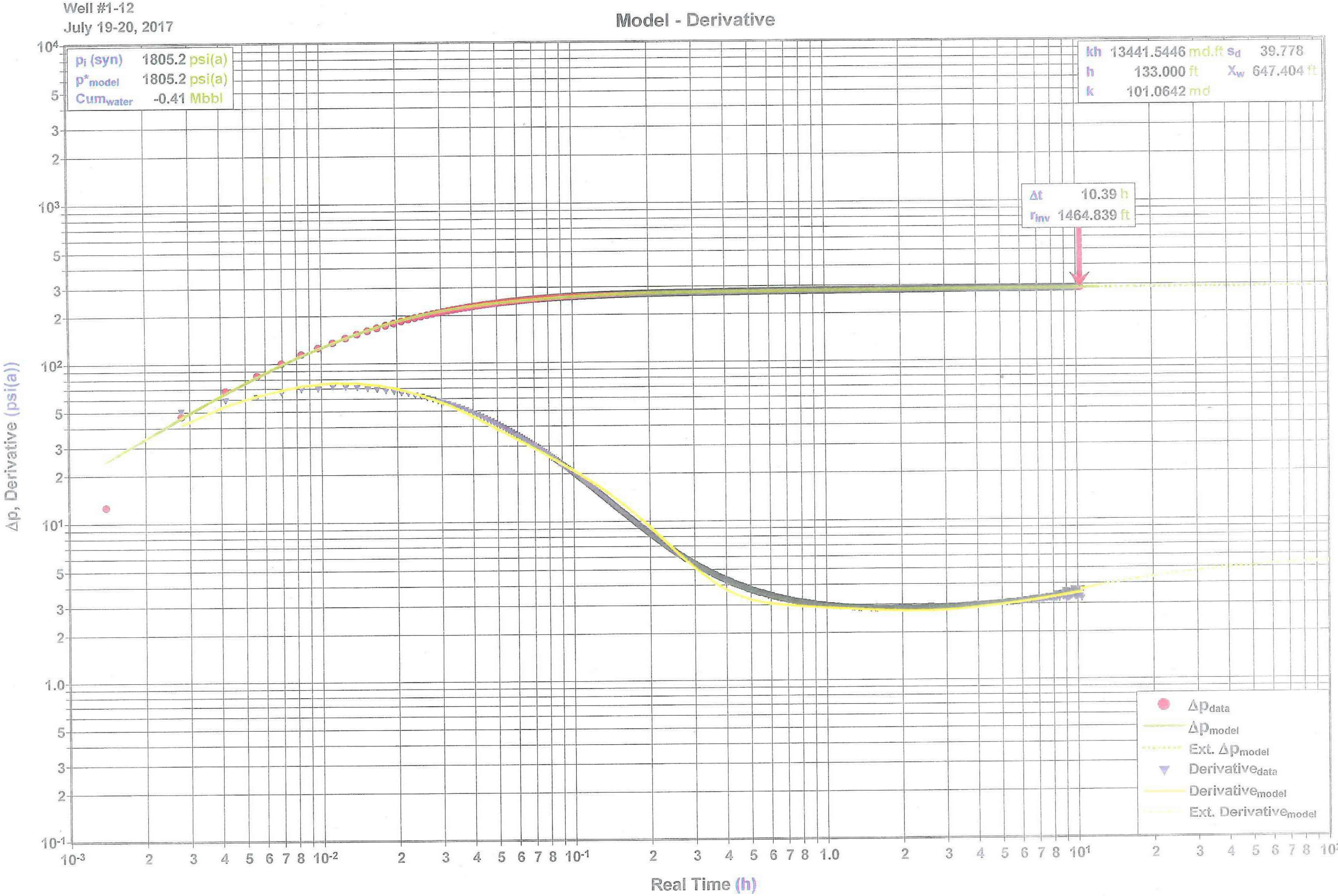


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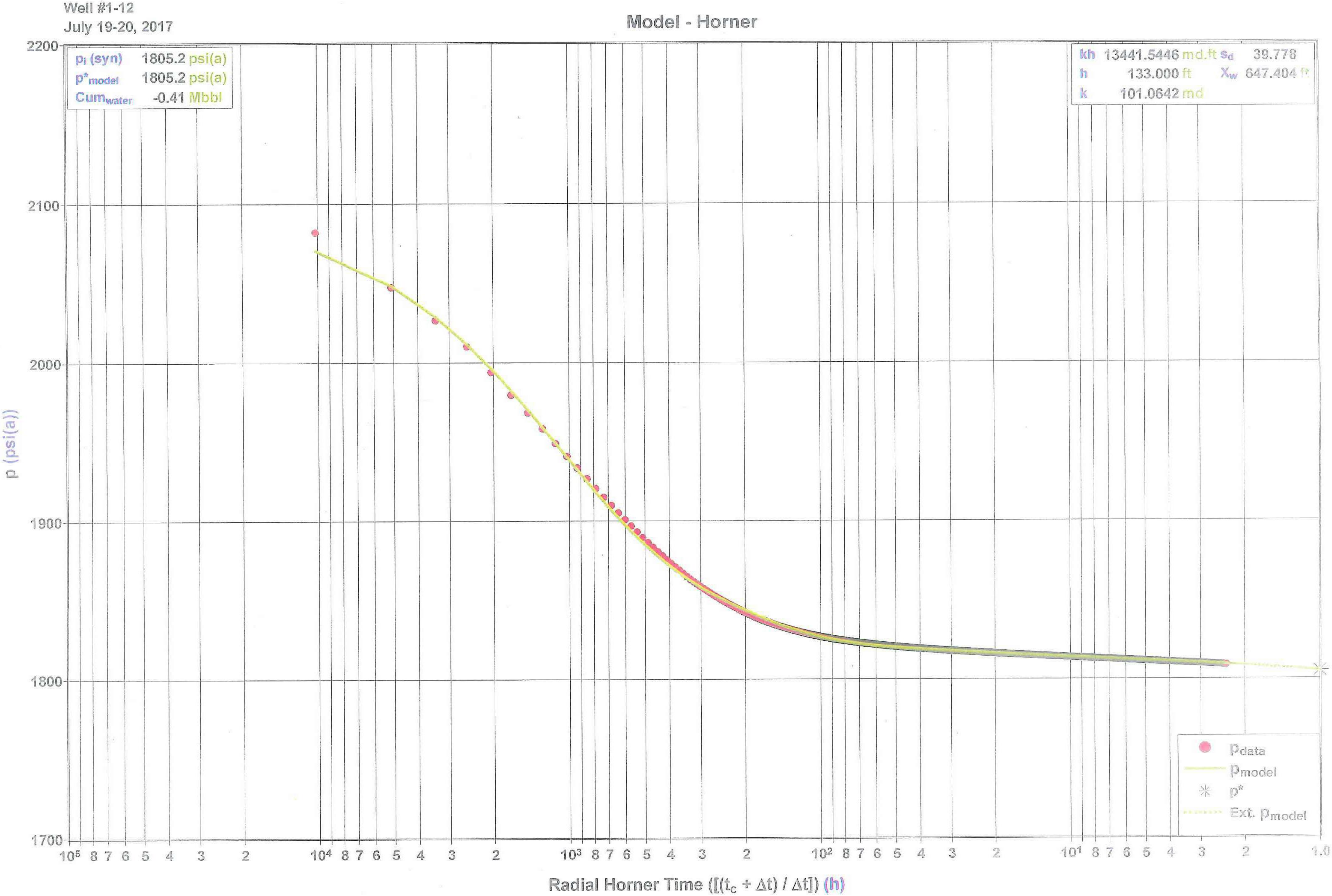
Figure 8 - Composite Model - Semilog Horner Match

Environmental Geo-Technologies, LLC
Well #1-12
July 19-20, 2017



WellTest32 2016 v2™ Ver 7.13.0.167
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Environmental GEO-Technologies, LLC

June 15, 2017

Mr. Allan Batka
United States Environmental Protection Agency
Region 5 (WU-16J)
77 West Jackson Blvd.
Chicago, Illinois 60604

SENT via U.S.P.S. & email

Mr. Stephen Jann
United States Environmental Protection Agency
UIC Section, (WU-16J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

Mr. Ray Vugrinovich
Michigan Department of Environmental Quality
Constitution Hall
525 West Allegan Street, South Tower, 1st Floor
Lansing, MI 48933

Re: Environmental Geo-Technologies, LLC – Romulus, Michigan
2017 MITs Notification Well #1-12 & #2-12
(UIC Permits: MI-163-1W-C010 & MI-163-1W-C011, Sections 1.H.3)

Dear Messrs. Batka, Jann and Vugrinovich:

Environmental Geo-Technologies, LLC ("EGT") hereby submits its request to conduct MITs of its Well Numbers 1-12 & 2-12 during the week of July 17-21, 2017 by Petrotek Engineering Corporation in conformance with the requirements of its two EPA UIC permits (#s MI-163-1W-C010 & MI-163-1W-C011, most notably Section I.H.3 of both permits).

Please accept this letter as notice that EGT will be conducting the aforementioned annual Mechanical Integrity Testing (MITs) at the EGT Romulus, Michigan facility during July of 2017. Included with this letter are proposed procedures for conducting the proposed MIT activities. In addition to applicable EPA regulations, they are based on applicable Region 5 input and procedures that have been approved and successfully utilized in past years at the facility. EGT will be utilizing Petrotek Engineering Corporation to complete this testing and requests that EPA and MDEQ accept additional communications directly from Petrotek regarding logistics for this MIT project as may be needed to complete the project. All communications with our technical consultant regarding this matter need to be copied to my attention.

EGT has tentatively scheduled Petrotek to complete the required MIT activiites during the period of July 17-21, 2017 in order to comply with annual deadlines but the schedule may be altered based on vendor and inspector availability. Injection falloff tests, annulus pressure tests, radioactive tracer logs and static temperature logs are scheduled to be performed on each of the two wells per the applicable annual deadlines. This suite of testing is intended to satisfy all mechanical integrity requirements needed for maintaining MITs compliance for this year.

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

At your convenience, please advise us regarding EPA and MDEQ plans for regulatory witnessing of the 2017 MIT activities so that we can coordinate with the UIC field inspectors regarding availability. Please do not hesitate to contact me at 734.946.1000 (or on my cellphone—313.674.1706) or our technical consultants Ken Cooper or Richard Schildhouse at Petrotek—303.290.9414—if you have any questions regarding this notice.

Sincerely,

Richard J. Powals, P.E.
Vice President

Att.

Cc: Stephen Roy—US EPA
Jeff McDonald—US EPA
Richard Schildhouse—Petrotek
Ken Cooper—Petrotek
John Frost---EGT
Patrick Sullivan---EGT
Tom Athans---EGT

jp061517/EGTEPAMITsRequest-2017

2017 ANNUAL MIT PROCEDURES
ENVIRONMENTAL GEO-TECHNOLOGIES, LLC - ROMULUS, MICHIGAN FACILITY

1. Annulus Pressure Tests – Well Nos. 1-12 and 2-12

   A. Ensure that well to be tested has been shut-in for a minimum of 36 hours. Record initial annulus tank level and annulus pressure. Record tubing injection pressure.

   B. Install certified test pressure gauge on annulus valve/test port.

   C. Pressurize well annulus to +/-875 to +/-925 psi. To ensure personnel safety and environmental protection, do not exceed normal operating pressure range without verification of relief/bypass valve (if present) and other surface equipment ratings/conditions.

   D. Allow annulus pressure to stabilize. The annulus may need to be pressurized and bled-off several times to ensure an absence of gas. Minimum specified annulus pressure listed in procedure 1.C must be maintained throughout one-hour test consistent with prior testing.

   E. Isolate annulus tank and pump from wellhead and test gauge.

   F. Monitor and record annulus pressure for one (1) hour at a minimum of ten (10) minute increments or as otherwise instructed by regulatory inspector with well shut-in. Pressure may not fluctuate more than 3% during the one-hour test.

   G. Open valves to allow annulus tank to communicate to wellhead. Note annulus tank level and annulus pressure. If needed, bleed annulus to normal operating pressure. Note final annulus tank level and pressure to verify communication with well annulus. Conduct any annual alarm testing requested by agency representative.

   H. Return monitoring and annulus system to service and return well to operator control.

   I. Provide copy of test gauge certification (>12 months old) to inspector on-site. Provide copy of field test records and certified annulus pressure gauge calibration data to agency in written report.

2. **Ambient Reservoir Pressure Monitoring, (Injection Falloff test) – Well Nos. 1-12 and 2-12**

   A. Inject into test well for a minimum of 12 hours prior to planned falloff. Attempt to maintain an approximately stabilized rate (+/-25%) at approximately 15 to 40 gpm as practical.

   B. Initiate shut-in or approximately stabilized rate injection rate into offset (non-test) well a minimum of 4 hours prior to planned shut-in for test well falloff.

C. Record rate and pressure data for both wells using existing monitoring equipment.

D. Conduct safety briefings, verify stabilized rate into active well(s) and rig-up lubricator on test well.

E. Run wireline conveyed pressure transducer to test depth (approximately 3,950' KB if practical) a minimum of 2 hours prior to planned shut-in. Collect data at minimum of 6-second intervals for a minimum of 5-minutes prior to shut-in and during fall-off test period.

F. Shut-in injection pump as quickly as practical and fully close all valves to isolate test well from injecting well (if active).

G. Continue monitoring bottomhole pressures for a minimum of 8 hours. After testing is complete, conduct four static gradient survey stops as the tool is pulled from well. Also record final gradient at wellhead in lubricator. Record static pressure and temperature data for a minimum of three (3) minutes at each gradient stop.

H. Submit both paper and electronic record of bottomhole pressure data along with downhole pressure transducer calibration information with analysis report.

3. **Radioactive Tracer Survey (RTS or RAT Logging) – Well Nos. 1-12 and 2-12**

A. Conduct safety briefings, verify wellhead conditions and rig-up lubricator on test well.

B. Run in well with RTS tool with collar locator and locate gamma-ray detector below injector port on tool. Iodine 131 to be used as tracer.

C. Correlate to existing logs (noting Kelly Bushing). Correlate RTS log to packer and/or natural gamma ray responses. Locate bottom of well if practical or run to at least 100 feet below casing shoe to a depth of not less than approximately 4,200 feet KB if attainable based on wellbore conditions and pull base log a minimum of depth of 3,093 feet KB, or shallower.

D. Run a minimum of one five-minute statistical log in two different lithologies. (approximate depths for bottom detector +/- 20 feet: Well #1-12 – 3,955 and 3,802 feet KB, Well #2-12 – 3,855 and 3,800 feet KB).

E. Start or continue injection at a rate that the operator is able to track the slug movement down-hole based on field supervisor observation and judgement of field conditions. Target rate likely to be 15 to 50 gpm.

F. Release the first slug in the tubing at a depth above the packer and observe the movement as it passes the lower detector. (approximate target depths for first slug release with ejector port +/- 20 feet: Well #1-12 – 3,100 feet KB, Well #2-12 – 3,750 feet KB). Move tool downhole and after catching the slug in the tubing at least twice, attempt to position the detector near the injection tubing tail. Once the slug is detected at the tubing tail, record the movement of the slug by repeatedly moving the tool down-hole and making a series of up-hole, overlapping passes as the slug dissipates into the injection formation. Five to eight passes as determined by the field supervisor may be necessary to complete the chase series. Note the top depth reached by the slug during the testing.

G. Continue to monitor the slug until it is dissipating into the injection zone. If a split occurs, monitor the upward moving slug until it is dissipating.

H. After the chase series is complete, pull tools into the tubing and release a slug at approximately 3,750 feet KB while injecting. RIH and position the bottom gamma-ray detector at a depth of approximately 4,080 feet KB (+/- 5 feet) in Well #1-12 and a depth of approximately 3,977 feet KB (+/- 5 feet) in Well #2-12 or as required by well conditions. Leave the tool stationary and record the log in time drive for a minimum of 30 minutes while continuing to inject.

I. After the time drive log is complete, run a final base log from bottom up over approximately the same interval as initial base log was run. Exceeding any minimum target standard identified in this procedure will be acceptable.

J. At the conclusion of the test, rig-down wireline RTS tools and support equipment and return well to operator control.

K. Submit both paper and electronic records of log data with analysis report.

4. **Static Temperature Log – Well Nos. 1-12 and 2-12**

A. Conduct safety briefings, verify wellhead conditions and rig-up lubricator on test well.

B. Verify that well to be tested has been shut in for a minimum of 36 hours. Conduct bucket test verification of temperature logging tool operations at ambient surface temperature and in ice water by comparison of tool temperature output to independent thermometer.

C. Rig-up pressure control equipment and temperature tool with gamma-ray and/or collar locator.

D. Run tool downhole at not more than an average speed of not greater than 30 feet per minute. Run log to at least 100 foot below bottom of tail pipe to a minimum depth of approximately 4,646 feet KB in Well #1-12 and 4,550 feet KB in Well #2-12 as practical based on wellbore conditions. Correlate log to existing logs using natural gamma-ray responses and/or known packer setting depth

E. Compare log to previous log(s) run in well of interest. Present temperature data on 1" and 5" per 100' scales.

F. If anomalies relevant to identifying potential upward flow out of the injection zone are indicated, run repeat log section, and/or run additional temperature log at subsequent shut-in time per guidance and/or perform additional logging near depth of anomaly.

G. Rig down equipment and return to standby or prepare for additional testing.

H. Submit both paper and electronic records of log data with analysis report.